CRITICAL ISSUE FAST PATH – RESOURCE ADEQUACY

Questions Received from Stakeholders

Question submitted after 3/15/2023 RASTF Meeting regarding PJM's Proposal

Roy Shanker

1. The notion of "expected" performance is used in multiple ways and appears to be different for different resources. Can the proposal provide a definition, possibly by resource type and example.

2. If a dynamic baseline is used, how will PJM then modify the ELCC analysis to reflect the change in resources quantity and possibly dispatch order based on that type of baseline? It seems incorrect to build up a dispatch amount and order ignoring this over the course of the year in the ELCC calculations.

    a. In turn, doesn't this mean that thermal resources must at least become one ELCC class? I can see doing it without that happening but it seems off.

3. The current PJM CETO and CETL analyses treat intermittent resources based on their thermal equivalent.
    a. How will that change for CETO when the ELCC value of the same resource decreases or increases every year?

    b. For CETL, there is a big question on how to do the right power flow for the test in general with intermittent/stochastic supply. This has to be addressed in some manner.

    c. Assuming for the moment we can't solve that, again in the current testing a thermal equivalent is used. Now each year that thermal equivalent will be different, but the underlying power flow (however it is characterized for the intermittent resource, will be the same, how do you plan on dealing with this.

        i. For this issue, how would you adjust the thermal resources in doing the test in terms of dynamic baseline, just consider summer?

4. All of 3 is an element of why assuming infinite transmission in the ELCC problem is heading for a train wreck. We have no way of dealing with locational ELCC. When adding 7-10,000 MW of offshore wind in the east, you are going to tank accreditation of western intermittent, tank price of eastern conventional and over accredit eastern ELCC. How is any of this addressed in the capacity proposal.

5. PJM proposes to make everything must offer. Presumably some parties with the option to offer capacity for sale, or not, will decide not to sell.

    a. How will you dispose of their CIRs? E.g. one year to sell, then they forfeit or something like that?

    b. How will this be treated in the interconnection process?

    c. How will this be reflected in the short-term headroom evaluations for annual incremental CIRs for all units with existing ISA's?

    d. There needs to be rules for this, e.g. you get one chance to pick, and you are either must offer capacity resource, or energy resource. After that, you lose CIRs and if want to change your mind you go to the back of the queue. Something like that.

6. You propose to excuse units from penalties if not dispatched by PJM during PAI. This implies that a unit might be notified right up to the beginning of the PAI?

    a. Does the excuse include notification and start up requirements

    b. If PJM has an excuse like this, won't some units not procure gas , or it become a game of chicken as to waiting for your notice versus not getting dispatched

        i. Couldn't this be avoided if units had an incentive to procure gas after alerts but before commitment decisions? E.g. Once alert issues the risk of reselling excess gas is shifted from the generator to uplift?

7. Wouldn't a simple fix remove the DPL S problem. E.g. all units with an option to offer or not offer must declare their intent x days before the posting of the planning parameters? Then the expected offers in the LDA would be known with certainty prior to the planning parameters being posted.

    a. Why wouldn't we do this in any future design (unless everything is must offer)?

    b. If we don't do this, why is the resulting risk any different that a bad load forecast (over or under forecast error risk)

8. Can you offer a flow chart or equivalent tracing a unit from its accreditation, to offer, to operation of the clearing engine and then determination of optimization result

    a. reflect CETL as described above

    b. how will the total average generation constraint be reflected in a marginal valuation representation of the resources.

Question submitted the next day. Prior to PJM's 3/29 Presentation

Roy Shanker

I think that the following hypothetical and related questions will integrate the first 8 questions I sent. The idea is to see how this proposal would actually be implemented and how it interacts with other market issues. (Most are capacity related, but there is some overlay with energy, most offer etc as shown below)

9. Hypothetical. Assume NJ adds the proposed 7000 MW(MFO) of off-shore wind. Let's assume it gets 2800 CIR's and is initially accredited for that amount under ELCC (40% marginal). (Also meets all other interconnection standards). Three years later, after 30,000 MW (MFO/nameplate) of wind is added in Com Ed, the NJ wind is now given an AUCAP of 1400 (e.g. 20% under a marginal regime). **Summarize for both year 1 and year 3** how the following would be addressed and calculated for the PS LDA (Assume just 1 LDA for the whole state) for the 7000 MW off shore facilities under the PJM straw Capacity Market proposal presented at the RASTF this week. (If you think it is necessary to have an average value for the ELCC class, explain why and how you would incorporate it into the answers, pick appropriate numbers consistent with the average also declining, but more slowly. I believe that PJM had forecast numbers that included this type of relative data in their ELCC presentations)

    a. Calculation of the NJ LDA CETO, what is the representation of the MW of the off-shore units (the unit) in the CETO calculation? For all these it is both year one and three and an explanation of the process to get the values.

    b. Calculation and representation of the unit in the CETL for the LDA.

    c. Calculation and representation of the unit in the Reliability Requirement as part of the Planning Parameters for the BRA.

    d. Calculation and representation of the unit in the baseline for the RTEP in terms of peak power flows.

    e. Calculation and representation of the unit in the determination of CIRs for the interconnection process if different from (d) for a given associated baseline.

    f. Calculation and representation of the unit (e.g. MWs) in determination of the MSOC (i.e. what are the MW assumed for the Net ACR calculation)

    g. Calculation and representation of the unit (e.g. MWs) in determination of MOPR (i.e. what are the MW assumed for the Net ACR calculation)

h. Calculation and representation of the units day ahead must offer energy requirement.

i. What would be the "Expected" output of the facility during a PAI for calculating penalty/bonus. (you can assume seasonal difference, but the question is confirm that the expected MWH change as the AUCAP goes from 2800 to 1400, which I am assuming would not happen but want to confirm)

j. Calculation and representation of the unit in the IRM study and the development of the FPR.

k. How would the unit be represented for purposes of any ancillary service sales under current rules but the different AUCAPs. Would moving to marginal representation change any of the metrics for the supply of ancillary services?

Questions submitted after the 3/29/2023 CIFP – RA Stage 1 Meeting

Roy Shanker

10. Explain if any of the answers to question (9) would be different to the parameters used in an incremental auction where accreditation for an ELCC resource changes.

11. In today's meeting (2023 3 29) PJM made a key statement that goes to the heart of my repeated comments that "ELCC is a tremendous planning tool, but not a market tool". In fact, you heard me express support for PJM using effectively a LDA based ELCC to establish the CETO and LDA Reliability Requirement going forward. This is a great application for a planning tool and I concur, (CETO related details to be discussed).

    However, in a very brief but very critically important statement, PJM also explained that the transition from a conclusion about the marginal ELCC accreditation that takes the attribute of the integral of the marginal reliability contribution aggregated over 8760 hours; and also takes this equivalence to other equal ELCC marginal integrals that reflect equal contributions to reliability, *and then converts these results into an 8760 hour auction product. This conversion is a key element of the use of the system wide ELCC in the RPM Auctions.* It was explained, similar to today, that this was the approach that PJM was going to follow. This more clear explanation of the "conversion process" was an articulate statement of all of my concerns.

    So far there has never been any well articulated basis for this conversion or the properties that result from doing this. I asked in the meeting what was the basis for this conclusion that the marginal integral will be properly represented by this leap in the BRA representation to an annual peak product. I believe Mike Cocco made a similar request.

a. There may be a good explanation that I have never understood, but at this stage we need a well defined answer. There may be a good one, but no one has offered it yet, and I am still not sure that this conversion doesn't result in unanticipated problems. (E.g. force very large/expensive new transmission "reliability" projects into the RTEP) Part of the concern is because this ELCC based marginal integral is the end point of evaluations that incorporate a great number of assumptions about the dispatch of the "non-ELCC" portion of the system. It is effectively a conditional probability marginal integral. And the conditional assumptions are very contentious to say the least. PJM presented information that small assumption changes in the conditional dispatch can change the results of the average (not marginal) results by about 30-50% (PJM, please feel free to correct this, I had trouble finding the old results). This is a strong reason for a full explanation and examples.

b. Thus, what is the basis for this leap in equivalence between the conditional marginal integral product equivalence and the representation of such equivalence as equal products that look like 8760 totally fungible capacity resources under the BRA clearing auction paradigm (and all its locational and annual IRM/FPR internal attributes)?

12. Given the answers to question 11, it should be clear that two different sets of ELCC portfolio and class values will be used. The one discussed in question 11 for CETO (which I believe will be an average not marginal value in the CETO calculation, but that also should be explained) and a second set of MARGINAL ELCC values (portfolio, class) that the PJM proposal will use for the accreditation of individual units (based on some unit performance allocation of the class value) for offers into the auction. (Again consider the conversion issue in question 11).

    a. With this in mind, which of these ELCC values at the unit level will be used in the FPR/IRM study. (See question 9) I believe from the comments today it will be the marginal values which reflect infinite transmission, not the LDA average (or marginal) values that will be used in the CETO. Explain whether what PJM is proposing here and why if not covered in response to question

    b. Relate this to the initial set of questions in (9) and what happens if the marginal value changes over time but the LDA average (or marginal) stays the same (or changes but in a different magnitude). This should be a reasonable possible result, but it needs to be explained to people.

    c. As asked in (9), but with the new understanding presented above from today's meeting and in question 11, which accreditation values and ELCC's will be used in the calculation of the CETL. Explain why the CETL will use different values than the CETO. (This is correct, but needs to be clearly explained to people, also which different values is clearly an issue)

d. Explain how the CETL unit representation and calculation will change as the different marginal RTO (No transmission limits) ELCC values change. (Again may be covered in 9) Explain why this is independent of the fact that the average (or marginal) ELCC accreditation and values for a unit in the CETO calculation might actually be unchanged. (Again this is a reasonable possible result, and makes sense to me, but needs to be explained)

e. Do any of these observations change the "conversion" assumption (discussed by PJM today and in question (11) of moving marginal ELCC results into the annual offers in the RPM auctions. Please explain.

Brad Heisey

1. In the Proposal Section there is a statement that relates to "fail to winterize", can you define how that would be measured or assessed and associate some date specific targets. The recently developed NERC EOP-012-1 has defined periods that allow for the completion of work set in phases and the timeline would have the work to meet their new standards R1 and R2 is 60 months after the EOP-012-1 Effective Date.

2. In the Proposed Standard Section there is a reference to being aligned with the IRC comments. My read of those comments have the historical temperature evaluation going back to 1973 and using the 0.02 percentile case. However as you point out the NERC standard sets the historical temperature horizon to be 1/1/2000. There is a significant difference in the design conditions depending on what temperature history range is used. Please clarify what PJM is proposing, the IRC comment range back to 1973 or the NERC standard range back to 2000.

Questions submitted by Roy Shanker on 4/5/2023 - after the 3/29/2023 CIFP – RA Stage 1 Meeting

Roy Shanker

13. For Energy Limited Capacity Resources, what will be their treatment with respect to "expected" output and PAI penalties under the following conditions:

    a. In anticipation of a PAI, PJM directs the Energy Limited facility to discharge/generate when it otherwise would not have, and as a result, the facility has less energy available than it would have during the subsequent PAI and incurs some or greater penalties than it otherwise would have without the PJM direction to operate.

        i. Explain if it would make a difference if the facility had a day ahead schedule,

ii. Explain how, if relevant, PJM would determine the "but for" output of the facility absent the PJM direction.

iii. Explain how PJM would treat the lost opportunity revenues if the PAI did not occur (e.g. would they be uplift, and if so how would they calculation, or would such revenues only be considered in the penalty calculation if a PAI occurred)

iv. Explain how this would be different from the status quo.

b. In anticipation of a PAI PJM directs the Energy Limited facility to no charge/pump when it otherwise would have, and as a result, the facility has less energy available than it would have during the subsequent PAI and incurs some or greater penalties than it otherwise would have without the PJM direction to operate.

i. Explain if it would make a difference if the facility had a day ahead schedule,

ii. Explain how, if relevant, PJM would determine the "but for" output of the facility absent the PJM direction.

iii. Explain how PJM would treat the lost opportunity revenues if the PAI did not occur (e.g. would they be uplift, and if so how would they calculation, or would such revenues only be considered in the penalty calculation if a PAI occurred)

iv. Explain how this would be different from the status quo.

c. Same as a) but the instruction to discharge/generate is also in PAI.

d. Same as b) but the instruction to not charge/pump is also in PAI.

14. Would any of the answers above change if the facility were utilizing PJM's storage/hydro optimizer?

a. If so, explain how you would treat schedules and dispatch and opportunity cost differently with respect to the above issues?

15. The above situations are indicative of a general issue in terms of "following dispatch being excused" for Energy Limited facilities. Will PJM propose a generic rule that can address the above and possibly other situations like them?

a. If not addressed above explain how this type of mechanism would work.

b. Could PJM classify the general types of issues that have been raised regarding excuses granted from PAI penalties in the 12/23-5/2022 events and how/why they have been resolved.

   i. Contrast the answer to this with what you happen under the new PJM proposal. Is there any general rule or set of principles that can be used to summarize the decision process. Please provide.

Question(s) Submitted on 4/9/2023---------------------

16. During the several weeks approximately 6 complaints have been filed at FERC related to winter storm Elliott. A common theme is the timing and notification of gas fired Capacity Resources in order for these resources to have sufficient notice to procure gas consistent with gas day nomination process and in these conditions operational flow orders.

    a. Please clarify exactly the notification process and "expected" performance for these types of facilities is under the status quo.

    b. Does the PJM new capacity proposal and the associated CP provisions make any changes that would clarify these types of situations for notification and timely natural gas nominations in the future?

    c. At the last meeting PJM stated that it would take into account parameter limits such as start-up and notification times in determining expected performance and deficiencies and related penalties during PAI.

       i. Can you clarify if and if so, how, gas nomination requirements and commitment decisions by PJM will be reflected in such parameter limitations in PJM's new RPM changes?

       ii. If they wont be considered, please explain.

17. One could envision that a fully firm gas fired resource could virtually always assure the availability of natural gas fuel by nominating sufficient quantities of gas (with firm transmission) to anticipate operating at full output for each operating day. If a gas fired facility did this, it would also likely have to liquidate some portion of its fuel supply any time it was not required to operate. Sometimes this might lead to a liquidation gain or loss with respect to the disposition of the excess natural gas.

    a. If a gas fired facility followed this fuel strategy, would PJM agree it is living up to the letter of being a fully firm Capacity Resource (ignore for now winterization etc.)?

b. If not, what other fuel procurement actions would PJM require to firm natural gas fuel supplies?

c. If such actions are consistent with a fully reliable natural gas fired Capacity Resource, explain how such a unit would represent its net liquidation gains or loss in its capacity and/or energy offers and the associated compensation and settlement. (Assume also that firm transmission costs are already in the Net ACR and the commodity costs are appropriately represented via an agreed fuel cost policy).

    i. E.g. the net liquidation gain or loss could be done on a forecast basis, become part of the Net ACR calculation, and set a higher (or lower) Net ACR and associated MSOC. This might allow recognition of these gains or losses in capacity market offers.

       Does PJM agree or disagree? Please explain.

    ii. E.g. The net liquidation costs could be established in actual operations and then determined and included as a debit or credit to uplift revenues/charges, because they are directly related to satisfying a firm energy requirement for being a firm Capacity Resource.

       Does PJM agree or disagree? Please explain.

    iii. If neither of the above two examples are acceptable, how does PJM anticipate such fuel liquidation net costs, necessary to assure the requirements to be a firm natural gas Capacity Resource would be compensated in its modifications to the RPM market in its proposal?